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(54) Title: HIGH DENSITY WELLBORE FLUID

(57) Abstract

A wellbore fluid comprises a glycol and an inorganic salt and has a density about 1.1 times greater than that of the glycol and/or contains about 25 to about 99 weight percent glycol and about 1 to about 75 weight percent inorganic salt and/or has a specific gravity of at least about 1.3 g/cc. The wellbore fluid is employed in well drilling, completion, and work-over operations (especially as a packer fluid).

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HIGH DENSITY WELLBORE FLUID

BACKGROUND

The present invention relates to (a) wellbore fluids of variable high density, (b) methods for using such wellbore fluids during or after drilling to (i) complete and/or treat a production or injection well or (ii) treat and/or modify a subterranean formation, and (c) natural resource systems containing such wellbore fluids. (As used in the specification and claims, the term "wellbore fluid" means a fluid used while conducting pay zone drilling, underreaming, drilling in, plugging back, sand control, perforating, gravel packing, chemical treatment, hydraulic fracturing, cleanout, well killing, tubing and hardware replacement, and zone selective operations as well as a fluid employed as a packer fluid.)

When completing deep, high pressure, high temperature wells, conventional packer fluids, whether oil- or water-based, have severe drawbacks. For example, zinc bromide-containing aqueous brines cause severe corrosion due to the pH of the zinc bromide solution and the corrosive combination of hydrogen sulfide and carbon dioxide with water.

Because the requisite packer fluid density increases with increasing well depth, packers fluids used in deep wells tend to be quite dense. Oil-based muds used as packers fluids in deep wells contain significant weighting agent concentrations to achieve the required density. One disadvantage of employing these oil-based muds as packer fluids is that, due to gravity, the weighting agent eventually settles out on top of the packer, creating a hard, cement-like weighting agent plug that could be about 100 m (328 ft) or more thick. (Furthermore, at downhole temperatures of about 148.9°C (300°F) and greater, the settling out of the weighting

agent is accelerated due to the thermal decomposition of suspending agents present in the oil-based drilling muds.) Getting through such plugs makes workover operations extremely costly and difficult.

5 In addition, aqueous-based fluids are not suitable for use as completion fluids in a clay-containing pay zone, because the water can cause swelling of clay-containing structures. To illustrate, reservoir rocks containing volcanic ash and/or smectic or mixed layer clays
10 could be permanently damaged if contacted with an aqueous-based fluid. Furthermore, brine-in-oil emulsions can cause clay swelling due to the internal water phase of the emulsion. Also, the emulsifiers present in brine-in-oil emulsions can produce detrimental formation wettability
15 changes.

SUMMARY OF THE INVENTION

Accordingly, there is a need for packer fluids that are non-aqueous for corrosion prevention, free of solids which can settle out on top of the packer, and
20 capable of achieving extremely high densities (such as about 2.2 g/cc (18 pounds per gallon (ppg))). There is also a need for solids-free, non-aqueous completion or wellbore fluids that do not adversely impact the oil-bearing subterranean formation.

25 The present invention solves these needs by providing (A) solids-free, non-aqueous wellbore fluids useful, for example, as packer, completion, and drilling fluids, (B) well completion, work-over, and drilling methods employing such fluids, and (C) natural resource
30 systems containing such fluids. The fluids of the present invention comprise a glycol and an inorganic salt, where substantially all of the salt is dissolved in the glycol. (As used in the specification and claims, the term "inorganic salt" means a salt devoid of any carbon atoms.)
35 Because glycols are highly polar, they are a good solvent

for the inorganic salts. In addition, the glycols (especially, ethylene glycol) tend to be inexpensive and thermally stable over a wide temperature range.

The glycol- and inorganic salt-containing solutions have a density at least about 1.1 times the density of the glycol and/or comprise about 25 to about 99 weight percent glycol and about 1 to about 75 weight percent inorganic salt and/or have a specific gravity (at about 0°C (32°F) referred to water at about 4°C (39.2°F)) of at least about 1.3 g/ml.

The wellbore fluids of the present invention can be employed in virtually any well drilling or completion or work-over operation (e.g., pay zone drilling, underreaming, drilling in, plugging back, sand control, perforating, gravel packing, chemical treatment, hydraulic fracturing, cleanout, well killing, tubing and hardware replacement, and zone selective operations). In addition, the wellbore fluids can be used as a packer fluid.

Regarding the natural resource system of the present invention, such system comprises a subterranean formation generally having a natural resource (e.g., crude oil, natural gas, and/or a geothermal fluid) present in at least a portion of the formation, a well penetrating at least a portion of the subterranean formation, and the wellbore fluid present, for example, in at least a portion of the well and/or the subterranean formation.

DETAILED DESCRIPTION OF THE INVENTION

The wellbore fluids of the present invention comprise one or more glycols and one or more inorganic salts. The glycols generally have a melting point less than about 22°C (71.6°F) (and preferably less than about 0°C (32°F)), a flash point greater than about 54.4°C (about 130°F), and a solubility in 100 g of water at 25°C (77°F) of at least about 25 g.

Exemplary glycols and some of their physical characteristics are listed in the following Table I.

TABLE IRepresentative Glycols

	Name	FP ¹ ,	Density,	MP ² ,	Viscosity,
		°C	g/cc	°C	cp @ 20°C
5	Ethylene gl ³	118	1.11	-13.5	21
	1,2-Propylene gl	99	1.04	-60	58.1
	1,3-Propylene gl		1.05		
	Diethylene gl	138	1.19	- 6.5	36
	Triethylene gl	172	1.13	- 4.3	49
10	Tetraethylene gl	191	1.13	- 4.1	
	Dipropylene gl	118	1.02	-40	107
	1,3-Butylene gl	121	1.01		
	1,4-Butylene gl	121	1.02	16	
	2,3-Butylene gl	85	1.05	23	
15	1,5-Pentanediol	129	0.99		
	2,4-Pentanediol	99	0.96		
	2,5-Hexanediol	104	0.96		37
	Ethylene gl monobutyl e ⁴	69	0.90	-70	6.4
	Ethylene gl monohexyl e	91	0.89	-50	5.2
20	Diethylene gl monomethyl e	93	1.02	-85	3.9
	Diethylene gl monoethyl e	96	0.99	-78	4.5
	Diethylene gl monobutyl e	116	0.95	-68	6.5
	Diethylene gl dimethyl e	70	0.95	-64	2.0
	Diethylene gl diethyl e	82	0.91	-40	1.4
25	Triethylene gl				
	monomethyl e	118	1.04	-44	7.3
	Triethylene gl				
	monoethyl e	135	1.02	-18	4.5
	Triethylene gl dimethyl e	111	0.99	-45	3.8
30	Triethylene gl				
	diacetate e	174	1.12	-61	11.7
	Diethylene gl methyl ace ⁵	82	1.04	-99	2.6
	Diethylene gl ethyl ace	110	1.01	-25	2.8

TABLE I (continued)
Representative Glycols

Name	FP ¹ ,	Density,	MP ² ,	Viscosity,
	<u>°C</u>	<u>g/cc</u>	<u>°C</u>	<u>cp @ 20°C</u>
5 Dipropylene gl				
monomethyl e	82	0.96	-80	3.7
Dipropylene gl monoethyl e	91	0.93		1.1
1. FP denotes flash point. 2. MP denote melting point. 3. gl denotes glycol. 4. e denotes ether. 5. ace denotes acetate.				

As used in the specification and claims, the term "glycols" also includes polyglycols. The preferred polyglycols include polyethylene glycols having a molecular weight of about 630 or less (e.g., polyethylene glycol 200, polyethylene glycol 400, and polyethylene glycol 600), polypropylene glycols, and ethylene oxide/propylene oxide copolymers. An interesting aspect of polyethylene glycols having a molecular weight of about 630 or less, polypropylene glycols having a molecular weight of about 1,000 or less, and ethylene oxide/propylene oxide copolymers is that, on heating, these polyglycols switch from being hydrophilic to being hydrophobic. Without being bound by the theory of operation, it is believed that this chameleonic characteristic can be desirable in certain applications such as when the wellbore fluid is employed as a drilling fluid or as a completion fluid. More specifically, hydroxyl group-containing hydrophobic compounds are thought to be less detrimental to water-sensitive clay formations than hydroxyl group-containing hydrophilic compounds. Accordingly, while the foregoing polyglycols are believed to be innocuous to water-sensitive clays and while the foregoing polyglycols are hydrophilic at ambient temperature, at elevated, subsurface temperatures the chameleonic polyglycols become hydrophobic

and, therefore, even more innocuous to water-sensitive clays.

The preferred glycols are selected from the group consisting of ethylene glycol, propylene glycol, 5 diethylene glycol, triethylene glycol, dipropylene glycol, butylene glycol, pentamethylene glycol, and hexamethylene glycol, with the most preferred glycols being ethylene glycol, propylene glycol, and diethylene glycol. (Propylene glycol has a low toxicity.)

10 Regarding the inorganic salts, exemplary inorganic salts include, but are not limited to, zinc halides, alkaline earth metal halides, cadmium halides, alkali metal halides, tin halides, arsenic halides, copper halides, aluminum halides, silver nitrate, mercury halides, 15 mercuric cyanide, lead nitrate, copper sulfate, nickel halides, cobalt halides, manganese halides, and chromium halides. The preferred halides are chlorine, bromine, and iodine; the preferred alkali metals are lithium, sodium, potassium, rubidium, and cesium; the preferred alkaline 20 earth metals are magnesium, calcium, strontium, and barium; and the most preferred salt is zinc halide, especially zinc bromide.

The concentration of the inorganic salt in the glycol depends on the desired density of the wellbore 25 fluid. In general, any concentration of salt up to the solubility limit of the salt in the glycol can be employed. While the wellbore fluid can contain a small concentration of dissolved inorganic salt (such as about 1, 5, 10, 15, 20, or 25, weight percent inorganic salt), the wellbore 30 fluid typically contains at least about 30, more typically at least about 35, even more typically at least about 40, and most typically at least about 45, weight percent dissolved inorganic salt. (As used in the specification and claims, the term "weight percent" when used to 35 designate the concentration of the dissolved inorganic salt in the wellbore fluid means the weight of the dissolved

inorganic salt in the glycol divided by the sum of the weights of the glycol and dissolved inorganic salt, the quotient being multiplied by 100 percent.) Preferably, the wellbore fluid contains at least about 50, more preferably
5 at least about 55, even more preferably at least about 60, and most preferably at least about 65, weight percent dissolved inorganic salt. Commonly, the solubility limit of the salt in the wellbore fluid is about 75 or less and more commonly about 70 or less, weight percent inorganic
10 salt.

In terms of density, a sufficient concentration of the inorganic salt is present in the wellbore fluid for the resulting glycol- and inorganic salt-containing solution to have a density at least about
15 1.1 times greater than the density of the glycol used in formulating the wellbore fluid. In fact, densities up to about 2.5 or more times that of glycol employed in making the wellbore fluid can be achieved. (Accordingly, the wellbore fluids of the present invention can be formulated
20 to achieve any density between about 1.1 and about 2.5 times that of the constituent glycol.)

In terms of specific gravity, the wellbore fluids of the present invention can be formulated to achieve any specific gravity (at about 0°C (32°F) referred
25 to water at about 4°C (39.2°F)) up to about 2.4 g/cc. (Thus, for example, the wellbore fluids of the present invention can be formulated to achieve any specific gravity between about 1.3 and about 2.4 g/cc.)

The wellbore fluids optionally contain one
30 or more additional ingredients such as proppants suitable for use in hydraulically fracturing subterranean formations, particulate agents suitable for use in forming a gravel pack, corrosion inhibitors, acids, bases, buffers, viscosifiers, antioxidants, organophilic clays, and fluid
35 loss control agents. Common proppants suitable for use in hydraulic fracturing procedures are quartz sand grains,

tempered glass beads, sintered bauxite, resin coated sand, aluminum pellets, and nylon pellets. Generally, the proppants are employed in the wellbore fluids of the present invention intended for use as hydraulic fracturing fluids and are used in concentrations of roughly about 0.12 g/cc (1 ppg) to about 1.20 g/cc (10 ppg) of the wellbore fluid. The proppant size is typically smaller than about 2 mesh on the U.S. Sieve Series scale, with the exact size selected being dependent on the particular type of formation to be fractured, the available pressure and pumping rates, as well as other factors known to those skilled in the art.

Typical particulate agents employed in the wellbore fluids of the present invention used as gravel packing fluids include, but are not limited to, quartz sand grains, glass beads, synthetic resins, resin coated sand, walnut shells, and nylon pellets. The gravel pack particulate agents are generally used in concentrations of about 0.12 g/cc (1 ppg) to about 2.41 g/cc (20 ppg) of the wellbore fluid. The size of the particulate agent employed depends on the type of subterranean formation, the average size of formation particles, and other parameters known to those skilled in the art. Generally, particulate agents of about 8 to about 70 mesh on the U.S. Sieve Series scale are used.

The corrosion inhibitor can be an inorganic and/or organic compound. Inorganic corrosion inhibitors include, but are not limited to, chromates (e.g., sodium chromate), phosphates (e.g., sodium phosphate), nitrites, silicates, borates, and arsenic. When used, the inorganic corrosion inhibitors are preferably present in the wellbore fluid in a concentration of at least about 0.0001, more preferably at least about 0.0005, and most preferably at least about 0.001, moles per liter of the wellbore fluid. The maximum concentration of the inorganic corrosion inhibitors in the wellbore fluid is generally less than about 0.1, preferably less than about 0.05, and more

preferably less than about 0.01, moles per liter of the wellbore fluid.

Exemplary organic compounds capable of functioning as a corrosion inhibitor in the wellbore fluid of the present invention include, but are not limited to, aniline, pyridine, butylamine, benzoic acid, benzosulfonic acid, nonamethyleneamine, diphenyl urea, carbon disulfide, allylthiourea, octyldecylamine, and hexadecylamine. When employed in the wellbore fluid, the organic corrosion inhibitors are preferably present in a concentration of at least about 0.1, more preferably at least about 0.5, and most preferably at least about 1, weight percent based on the entire weight of the wellbore fluid (i.e., the weight of glycol, inorganic salt, and any other ingredient present in the wellbore fluid). Typically, the maximum concentration of the organic corrosion inhibitor in the wellbore fluid is less than about 10, preferably less than about 5, and most preferably less than about 2.5, weight percent based on the entire weight of the wellbore fluid.

Acids, bases, and buffers are employed in the wellbore fluid to help maintain the dissolved inorganic salts in solution when the wellbore fluid is contacted by subterranean materials (e.g., water) having a pH capable of precipitating the dissolved salts. The acid can be one or more inorganic and/or organic compounds. Common inorganic acids are hydrochloric acid, hydrobromic acid, hydrofluoric acid, nitric acid, phosphoric acid, orthophosphoric acid, sulfurous acid, sulfuric acid, boric acid, carbonic acid, chromic acid, hydroiodic acid, percholic acid, and aluminic acid. Typical organic acids include oxalic acid, formic acid, caprylic acid, oleic acid, ascorbic acid, benzoic acid, butyric acid, lactic acid, acetic acid, and citric acid.

The base can be one or more inorganic and/or organic compounds. Illustrative inorganic bases are hydroxides (e.g., ammonium, alkali metal, and alkaline

earth metal hydroxides), bicarbonates (e.g., alkali metal bicarbonate), carbonates (e.g., alkali metal carbonates), lime, and ammonia. Exemplary organic bases are acetamide, ethylenediamine, hydrazine, pyridine, benzylamine, butylamine, thiazole, toluidine, and urea.

The buffering agents employed in the present invention generally have a buffering capacity in at least a portion of the pH range of about 6 to about 8, preferably about 6.5 to about 7.5, and most preferably about 6.8 to about 7.2. Buffer agents having a buffering capacity in at least a portion of the above pH ranges are set forth in Lange's Handbook of Chemistry, Editor: John A. Dean, 12th Edition, McGraw-Hill Book Co., New York, NY (1979), pages 5-73 to 5-84, this publication being incorporated herein in its entirety by reference. More specifically, phosphates (e.g., potassium dihydrogen phosphate, disodium monohydrogen phosphate), phosphate-hydroxide combinations (e.g., potassium dihydrogen phosphate and sodium hydroxide), phosphate combinations (e.g., potassium dihydrogen phosphate and disodium monohydrogen phosphate), 2-(N-morpholino)ethanesulfonic acid-sodium hydroxide combinations, 2,2-bis(hydroxymethyl)-2,2',2''-nitriloethanol-hydrochloric acid combinations, potassium dihydrogen phosphate-borax combinations, N-tris(hydroxymethyl)methyl-2-aminoethanesulfonic acid-sodium hydroxide combinations, triethanolamine-hydrochloric acid combinations, and diethylbarbiturate-hydrochloric acid combinations are some of the buffering agents having a buffering capacity within at least a portion of the aforementioned pH ranges.

The concentration of acid, base, or buffer employed in the wellbore fluid is dependent upon the subterranean conditions that the wellbore fluid is expected to encounter (e.g., the amount and pH of subterranean water expected to be in contact with the wellbore fluid). In general, when employed, the acid, base, or buffer is used in a concentration of at least about 0.01, preferably at

least about 0.05, and more preferably at least about 0.1 weight percent based on the entire weight of the wellbore fluid. Typically, the maximum concentration of the acid, base, or buffer in the wellbore fluid is less than about 10, preferably less than about 5, and more preferably less than about 1, weight percent based on the entire weight of the wellbore fluid.

Exemplary antioxidants employed in the present invention are 2,6-ditertbutyl-p-cresol, butylated-hydroxy-anisole (BHA), butylated-hydroxy-toluene (BHT), tert-butyl-hydroquinone (TBHQ), o-cyclohexylphenol, and p-phenylphenol. When used, the antioxidants are generally present in the wellbore fluid in a concentration of at least about 0.0015, preferably at least about 0.01, and more preferably at least about 0.1, but typically less than about 10, preferably less than about 5, and more preferably less than about 1, weight percent based on the entire weight of the wellbore fluid.

The wellbore fluid of the present invention generally contains little, if any, water. Typically, the wellbore fluid contains about 50 or less, more typically about 40 or less, even more typically about 30 or less, and most typically about 20 or less, weight percent water based on the entire weight of the wellbore fluid. Preferably, the wellbore fluid contains about 10 or less, more preferably about 5 or less, even more preferably about 1 or less, and most preferably about 0.5 or less, weight percent water based on the entire weight of the wellbore fluid. In fact, it is not unusual for the wellbore fluid to contain even smaller concentrations of water (e.g., less than about 0.1, 0.05, or 0.01, weight percent water based on the entire weight of the wellbore fluid) or to be anhydrous.

In addition, when used as a packer or completion fluid (or other fluid where the presence of solids can detract from or be detrimental to the performance of the fluid), the wellbore fluid contains

little, if any, solids (such as weighting agents (e.g., barite)). Commonly, such wellbore fluids contain about 10 or less, more commonly about 7.5 or less, even more commonly about 2.5 or less, and most commonly about 1 or less, weight percent solids based on the entire weight of the wellbore fluid. Preferably, the wellbore fluid contains about 0.5 or less, more preferably about 0.1 or less, even more preferably about 0.05 or less, and most preferably about 0.01 or less, weight percent solids based on the entire weight of the wellbore fluid. Furthermore, it is not unusual for these wellbore fluids to contain even smaller solid concentrations (e.g., less than about 0.005, 0.001, or 0.0005, weight percent solids based on the entire weight of the wellbore fluid).

The salt-containing wellbore fluid of the present invention is prepared by dissolving the inorganic salt in the glycol, preferably with vigorous stirring. Generally, the inorganic salt is added slowly or incrementally to the glycol to allow the added salt to dissolve prior to adding any significant amount of additional salt. Heat can be employed to increase the dissolution rate of the inorganic salt in the glycol. In addition, acids, bases, buffering agents, and antioxidants are typically added to the glycol either before, during, or after the addition of the salt.

The resulting wellbore fluid is preferably stored under conditions which prevent adsorption of water (e.g., stored in air tight containers) because glycols tend to be very hygroscopic. (Adsorbed water is undesirable because it decreases the density of the wellbore fluid and makes the wellbore fluid corrosive.)

The specific techniques used when employing the wellbore fluid of this invention are determined by its intended use and are analogous to methodologies employed when using prior art wellbore fluids for corresponding well drilling or completion or work-over operations. For

example, when the wellbore fluid is employed as a gravel packing fluid, it is typically injected into the formation in accordance with the procedure discussed in U.S. Patent 4,552,215, this patent being incorporated herein in its entirety by reference.

When employed as a fracturing fluid, the wellbore fluid of the present invention is usually injected or otherwise introduced into the formation using procedures analogous to those disclosed in U.S. Patent 4,488,975, U.S. Patent 4,553,601, Howard et al., Hydraulic Fracturing, Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., New York, NY (1970), and Allen et al., Production Operations, Well completions, Workover, and Stimulation, 3rd Edition, Oil & Gas Consultants International, Inc., Tulsa, Oklahoma (1989) (Allen), volume 2, chapter 8, these publications being incorporated herein in their entireties by reference.

When employed in a perforating operation, the wellbore fluid of the present invention is used according to the methodologies disclosed in volume 1, chapter 7 of Allen, this publication being incorporated herein in its entirety by reference.

One of the most important applications of the wellbore fluid is in the capacity of a packer fluid during packer setting operations, such as those discussed in volume 1, chapter 6 of Allen. (Volume 1, chapter 6 of Allen is also incorporated herein in its entirety by reference.)

In addition, the wellbore fluid can be used as a well killing fluid to kill a well, using procedures such as those discussed in volume 1, chapter 8 of Allen, which is also incorporated herein in its entirety by reference.

EXAMPLES

The following examples are intended to illustrate, and not limit, the invention. Example 1 details the preparation of an exemplary wellbore fluid of the present invention.

EXAMPLE 1Dissolution of an Inorganic Salt In a Glycol

Ethylene glycol (about 50 cc) was placed into a 150 ml beaker on a hot plate. ZnBr₂ was added to the ethylene glycol in about 10 g increments with gentle stirring, with the temperature of the hot plate at about 65.6°C (150°F). The resulting clear fluid was placed into a 10 ml graduated cylinder, allowed to cool, and then put on a balance to determine its density. The 10 ml of fluid weighed about 21.6 g and, therefore, had a density of about 2.16 g/cc (17.96 ppg). The cooled fluid was fairly thick, but still pourable. It remained clear, even after cooling, indicating that the ZnBr₂ was still dissolved.

Although the present invention has been described in detail with reference to some preferred versions, other versions are possible. Therefore, the spirit and scope of the appended claims should not necessarily be limited to the description of the preferred versions contained herein.

CLAIMS

1. A wellbore fluid comprising: (a)
a glycol; and
(b) an inorganic salt,
5 where substantially all of the salt is dissolved in the glycol to form a solution having a density at least about 1.1 times the density of the glycol.
2. A wellbore fluid comprising: (a)
about 25 to about 99 weight percent glycol; and
10 (b) about 1 to about 75 weight percent inorganic salt,
where substantially all of the salt is dissolved in the glycol.
3. A wellbore fluid comprising: (a)
15 a glycol; and
(b) an inorganic salt,
where substantially all of the salt is dissolved in the glycol to form a solution having a specific gravity (at about 0°C (32°F) referred to water at about 4°C (39.2°F))
20 of at least about 1.3 g/ml.
4. The wellbore fluid of any one of claims 1-3 where the glycol has a specific gravity (at about 0°C (32°F) referred to water at about 4°C (39.2°F)) of at least about 0.8 g/ml (6.6 pounds per gallon (ppg)) and a flash
25 point of greater than about 54.4°C (130°F).
5. The wellbore fluid of any one of claims 1-3 where the glycol is selected from the group consisting of ethylene glycol, propylene glycol, diethylene glycol, triethylene glycol, dipropylene glycol, butylene glycol,
30 pentamethylene glycol, hexamethylene glycol, ethylene glycol monobutyl ether, ethylene glycol monohexyl ether, diethylene glycol monomethyl ether, diethylene glycol monoethyl ether, diethylene glycol monobutyl ether, diethylene glycol dimethyl ether, diethylene glycol diethyl

ether, triethylene glycol monomethyl ether, triethylene glycol monoethyl ether, triethylene glycol dimethyl ether, triethylene glycol diacetate ether, diethylene glycol methyl acetate, diethylene glycol ethyl acetate,
5 dipropylene glycol monomethyl ether, dipropylene glycol monoethyl ether, polyglycols, and mixtures thereof.

6. The wellbore fluid of any one of claims 1-5 where the inorganic salt is selected from the group consisting of zinc halide, alkaline earth metal halide,
10 cadmium halide, alkali metal halide, tin halide, arsenic halide, copper halide, aluminum halide, silver nitrate, mercury halide, mercuric cyanide, lead nitrate, copper sulfate, nickel halide, cobalt halide, manganese halide, chromium halide, and mixtures thereof.

15 7. A method for the drilling or completion or work-over of a well, the method comprising the step of drilling or completing or working-over a well with a drilling or completion or work-over fluid, respectively, the method being characterized by employing the wellbore
20 fluid of any one of claims 1-6 as the respective drilling or completion or work-over fluid.

8. A natural resource system comprising:
(1) a subterranean formation;
(2) a well penetrating at least a
25 portion of the subterranean formation; and
(3) the wellbore fluid of any one of claims 1-6 present in at least a portion of the well.

9. A natural resource system comprising:
(1) a subterranean formation;
30 (2) a wellbore penetrating at least a portion of the subterranean formation;
(3) a casing positioned within at least a portion of the wellbore;
(4) a tubing positioned within at least
35 a portion of the casing;

(5) a packer positioned between the outside surface of the tubing and the inside surface of the casing; and

(6) a packer fluid located in at least
5 a portion of the volume defined by the outside surface of the tubing, the inside surface of the casing, and the top surface of the packer,
where the packer fluid is the wellbore fluid of any one of claims 1-6.

10 10. A natural resource system comprising:
(1) a subterranean formation;
(2) a wellbore penetrating at least a
portion of the subterranean formation;
(3) a casing positioned within at least
15 a portion of the wellbore; and
(4) the wellbore fluid of any one of
claims 1-6 present in at least a portion of the
subterranean formation proximate the wellbore.

20 11. A drilling system comprising:
(A) a subterranean formation;
(B) a borehole penetrating the
subterranean formation;
(C) a drill bit suspended in the
borehole; and
25 (D) a drilling fluid located in the
borehole and proximate the drill bit,
where the drilling fluid is the wellbore fluid of any one
of claims 1-6.

30 12. A method for drilling a borehole in a
subterranean formation, the method comprising the steps of:
(I) rotating a drill bit at the bottom
of the borehole and
(II) introducing a drilling fluid into
the borehole (i) to pick up drill cuttings and (ii) to
35 carry at least a portion of the drilling cuttings out of
the borehole,

where the drilling fluid is the wellbore fluid of any one of claims 1-6.

13. A method for setting a packer comprising the step of setting a packer in a casing in the presence of a packer fluid, characterized in that the packer fluid comprises the wellbore fluid of any one of claims 1-6.

INTERNATIONAL SEARCH REPORT

International Application No
PCT/US 95/15855

A. CLASSIFICATION OF SUBJECT MATTER
IPC 6 C09K7/06

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 6 C09K

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WO,A,94 06883 (UNION OIL COMPANY OF CALIFORNIA) 31 March 1994 see page 1, line 3 - line 22 see page 3, line 32 - page 4, line 15 see page 9, line 26 - page 10, line 2; table I	1,6
A	--- WO,A,92 14798 (D.BRANKLING) 3 September 1992 see page 3, line 22 - page 4, line 32 see examples 1,2	1,5,6
A	--- GB,A,2 223 255 (SHELL INTERNAT. RES. MAATS.) 4 April 1990 see page 3, line 22 - page 4, line 26 see claims 1-14 --- -/--	1,5,6

☒ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

* Special categories of cited documents:

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- *P* document published prior to the international filing date but later than the priority date claimed

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- *A* document member of the same patent family

Date of the actual completion of the international search

15 April 1996

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No

PCT/US 95/15855

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
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		US-A- 5072794	17-12-91
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		DE-D- 69115569	01-02-96
		EP-A- 0461584	18-12-91
		US-A- 5141920	25-08-92

INTERNATIONAL SEARCH REPORT

International Application No

PCT/US 95/15855

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	<p>US,A,5 057 234 (R.G.BLAND) 15 October 1991 see column 2, line 36 - line 55 see column 3, line 45 - column 4, line 33 see column 4, line 60 - column 5, line 16 -----</p>	1,5,6

Form PCT/ISA/218 (continuation of second sheet) (July 1992)